BEFORE THE PUBLIC
SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC, for Authority to Adjust Electric, Natural Gas, and Steam Rates	Docket No. 5-UR-109

DIRECT TESTIMONY OF PAUL CHERNICK

I. Summary and Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: My name is Paul L. Chernick. I am the president of Resource Insight, Incorporated, 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight since 1990. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective

review of generation-planning decisions, ratemaking for plants under construction, ratemaking for excess and/or uneconomical plants entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Ex.-Sierra Club-Chernick-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. This previous testimony has included many reviews of the economics of power plants, utility planning, marginal costs, and related issues.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Sierra Club.

Q: What is the scope of your testimony?

A: I review the economics of the coal plants owned by a Wisconsin electric-utility subsidiary of WEC Energy, Wisconsin Electric Power Company (the Company, WEPCo, or WEP), which is one of the applicants in the proceeding in which this testimony is filed. My purpose is to determine whether WEPCo was prudent in retiring the Pleasant Prairie Power Plant and the Presque Isle Power Plant, and whether continued operation of WEPCo's other coal plants would be prudent. I also

question the inclusion of some dues and contributions in the WEPCo and Wisconsin Gas expenditures.

My testimony relies on numerous WEPCo documents and discovery responses (some of which are confidential), including the testimony of WEPCo witness Richard Stasik, as well as publicly available documents from Wisconsin Power and Light (WPL), Madison Gas and Electric (MGE), the Energy Information Administration (EIA), the Mid-Continent Independent System Operator (MISO), the Federal Energy Regulatory Commission (FERC), and the Environmental Protection Agency (EPA).

Q: Why focus your testimony on the Company's coal units?

A: Keeping the existing coal units in service is expensive, compared to the costs of the gas-fired units. Economic operation of coal units is heavily dependent on having a large number of hours in which market prices are higher than the costs of fuel and other operating costs for starting the units and generating electricity. Since each coal unit is much less nimble than most gas-fired or hydro plants, those profitable hours also need to be predictable days in advance and must occur in clusters long enough to pay for the costs of cycling the unit up and down. The addition of large amounts of wind regionally has reduced the profitability of coal plants more than for most other types of generation. In order to be cost-effective, coal plants must operate in most hours of the year; low off-peak prices are more problematic for coal plants than for gas combined-cycle units, for example. Due to their limited cycling ability, coal units are frequently required to operate at a loss in low-priced hours, in order to be available in high-priced hours, while most other plants would either earn a little margin even at low price (e.g., run-of-river hydro) or shut down for the low-priced hours (e.g., gas combined-cycle).

Q: What information did the WEPCo provide in its Application relevant to determining whether its existing generation remains used and useful?

A: For the most part, WEPCo did not provide information in its Application relevant to determining whether its existing generation remains used and useful and continued investment in them is prudent. While WEPCo claimed that it "continuously reviews the performance of all the plants in its generating fleet in making decisions concerning their operations,"[1] it failed to provide projected retirement dates for those plants when asked and simultaneously claimed that "[o]utside of annual Fuel Plans, no analyses [of the economics of continued operation of one or more of WEPCo's coal plants that have been conducted by or for WEPCo since January 2014] exist for plants other than Pleasant Prairie and Presque Isle."[2]

Q: Which coal capacity does WEPCo own?

A: WEPCo owns all or parts of thirteen coal units, of which two units were retired in 2018 (Pleasant Prairie 1 and 2) and five units were retired in 2019 (Presque Isle 5-9), as summarized in Table 1.

Table 1: Operating and Recently Retired WEPCo Coal Plants

Plant	Unit(s)	Year Installed[a]	Retirement Year[b]	Summer Capacity (MW)[c]	Operator	2018 WEPCo Share	
						Percent[d]	MW[e]
Elm Road	1-2	2010		1,268	WEPCo	83.34%	1,056.8
Oak Creek	5-8	1967		995	WEPCo	100.00%	995
Pleasant Prairie	1-2	1985	2018	1,188	WEPCo	100.0%	1,188
Presque Isle	5-9	1979	2019	359	WEPCo	100.0%	359

Data sources:

[a,b] 2017 FERC Form 1, p. 402

[c] 2017 EIA 860

[d] 2017 EIA 860, Owner file

[e] Percent times Capacity

[1] WEPCo Resp. to KHM 11(PSC REF# 366603)

[2] WEPCo Resp. to Sierra Club 1.20 and 1.21 (PSC REF# 370971 and 370448)

Q: Who owns the remainder of Elm Road?

A: Table 2 summarizes the ownership shares.

Table 2: Co-owners of Elm Road

Plant	Unit(s)	WEPCo	WPPI	MGE
Elm Road	1-2	83.34%	8.33%	8.33%

Q: How are the WEPCo units dispatched?

A: The WEPCo units sell all their output to the MISO market and WEPCo purchases all energy required for load from MISO. Thus, the value of the power plants and the costs of serving customers are distinct.

The operation of the WEPCo units should be determined by the hourly market prices of energy. As I discuss in Sections IV.A and V, WEPCo requires that MISO commit the Elm Road and Oak Creek units every day, to run at their minimum load, with market prices determining only whether they operate above those levels.

Q: Does it appear that continued operation of the WEPCo coal capacity is beneficial to ratepayers?

A: No. The costs of fuel, operating and maintenance (O&M), overheads, and ongoing capital additions for both of the two remaining Oak Creek units appear to substantially exceed the market value of their output. The Elm Road units also may be operating at a loss. The decision to keep a unit online for one or more years constitutes a commitment to pay the fixed O&M, overheads, and capital additions needed to keep it running. Thus, whatever profit the utility makes in the high-priced hours, minus losses from unavoidable operation in the low-priced hours, plus small value streams from capacity and miscellaneous revenues, must cover all the fixed annual costs. For Oak Creek, and possibly Elm Road, that is no longer the case.

Replacement resources, especially wind, are less expensive energy sources than continued operation of the coal plants. To the extent that WEPCo requires additional capacity to meet its MISO obligations, beyond what is provided by replacement wind energy, it can purchase capacity credits (which are very inexpensive), and build or purchase solar and/or storage resources.

Q: Do your estimates of the costs the coal units include recovery of the previous investment in those resources?

A: No. I compare the going-forward costs of the plants with the costs of replacing their energy and capacity. The total costs of the coal units is higher than those going-forward costs.

Q: Do your conclusions rely on any specific assumptions about the recovery of the unamortized capital cost of the retired plants?

A: No. I do not include any sunk capital costs in my analysis. My conclusion is that ratepayers are losing money on the continued operation of the plants. Customers would be better off with retirement of the plants, even if they continue to pay for depreciation and return on the sunk costs, just as if the plants were in service. WEPCo can be made whole, and ratepayer costs can be reduced even further, if the unamortized investment can be securitized and refinanced at a lower cost of capital.

Q: How does WEPCo take economics into account in deciding whether to retire its fossil plants?

A: As stated earlier, WEPCo claims that it has not conducted any analysis of the economics of continued operation of its coal units other than ones it has already retired. Further, when asked to provide estimated retirement dates for its plants WEPCo failed to provide an answer, only stating that, “continuously reviews the

performance of all the plants in its generating fleet in making decisions concerning their operations."[3]

Q: How should the Commission deal with WEPCo's coal plants?

A: None of WEPCo's remaining coal plants appears to be profitable, and there is little chance that they will become profitable over their remaining life. Ratepayers should not be charged for the costs of keeping the plants operating unprofitably. Thus, the Commission should disallow some combination of (1) depreciation and return on the capital additions for the coal units since the last rate proceeding, (2) future O&M for plants that should not be running and losing money for ratepayers, and (3) fuel costs for the times when the plants are operating uneconomically. Since fuel costs are recovered in other proceedings, I do not consider that option here. As shown in Table 22, the losses from Elm Road and Oak Creek have averaged around $98 million annually.[4] Excluding $98 million from WEPCo's annual revenue requirements would relieve ratepayers of that burden going forward.[5]

Q: What other steps should the Commission take with respect to these units?

A: The Commission should warn WEPCo that cost recovery for these units in any future rate case will be contingent on a showing that incremental investments and operating costs are justified by the continued operation of the resources. The Commission should also require that WEPCo demonstrate that it is taking measures

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[3] WEPCo Resp. to KHM 11(PSC REF# 366603)

[4] See Table 26 for a refinement, using confidential information.

[5] If WEPCo can demonstrate that some of the losses I estimate below would have occurred, even had WEPCo prudently reviewed the economics of continued operation of Elm Road and Oak Creek and taken prudent steps to reduce its expenditures for units that should be retired in the near term, the disallowance can be reduced accordingly.

that may be required to retire uneconomic plants, including transmission studies and procurement of resources.

III. Public Data on Performance and Costs of WEPCo Coal Units

Q: What performance and cost components of the coal units have you reviewed?

A: I have compiled performance data on unit capacity factor, forced outage rate, availability, and heat rate. I have also assembled cost data for fuel, variable O&M, fixed O&M, overheads, and capital additions.

A. Performance Measures

Q: Which performance measures have you compiled for the WEPCo coal units?

A: Table 3 shows data on each coal unit's 2018 capacity factor, 2018 heat rate, and the average forced outage rate that MISO reports for coal units of the size of each of the WEPCo units.

Table 3: Coal Plant Technical Performance

Plant	Unit	2018 Capacity Factor[a]	2018 Heat Rate[b] (Btu/kWh)	MISO Average Forced Outage Rate[c]
Oak Creek	1-2	66%	10,427	9.28%
Elm Road	4	67%	10,562	9.82%
Pleasant Prairie	7-8	33%	11,629	4.60%
Presque Isle	3	42%	10,600	9.82%

[a] *from EIA 860 and 923.*

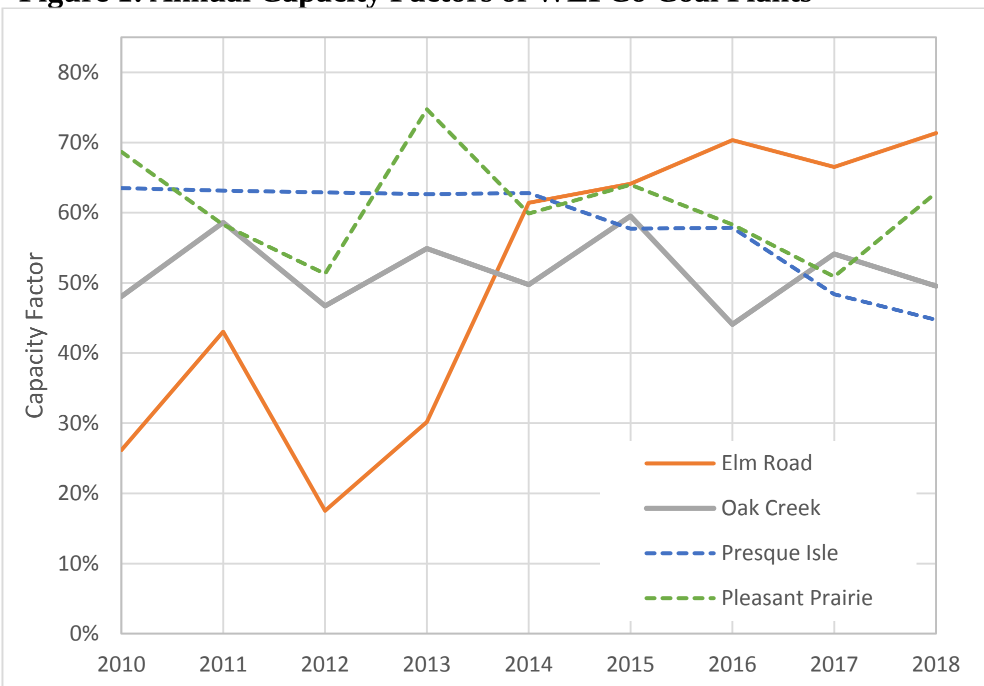
[b] *2018 EIA Form 923.*

[c] *"Planning Year 2019–2020 Loss of Load Expectation Study Report," Loss of Load Expectation Working Group, October 17, 2018, Table 4-1.*

Q: **How has coal utilization changed?**

A: Figure 1 depicts annual capacity factors by unit for the last nine years, from EIA forms 860 and 923. The solid lines represent operating plants while the dashed lines represent retired plants.

Figure 1: Annual Capacity Factors of WEPCo Coal Plants



Most strikingly, Oak Creek has consistently run less than the retiring plants. It only outperformed Pleasant Prairie in one of the nine last years, and outperformed Presque Isle in three. Elm Road Units 1 and 2 were only installed in 2010 and 2011, respectively, which accounts for its low capacity factors at the start of this analysis period. However, after 2014, it consistently out-performed the retiring plants and Oak Creek.

B. Fuel and O&M

Q: **What public information do you have on the fuel and O&M costs of WEPCo's coal units?**

A: I have the following data on O&M:

- the fuel and O&M cost data that WEPCo and Madison Gas and Electric file in the 2012–2018 FERC Form 1 reports for each unit,
- variable O&M by unit from the Bloomberg New Energy Finance study.

Table 4 provides data on the fuel and total nonfuel O&M costs for each of the coal units, in dollars per megawatt-hour, from the WEPCo FERC Form 1 reports for those years, pages 402 and 403.

Table 4: Fuel and Non-Fuel O&M Costs by Coal Plant ($/MWh)

		2012	2013	2014	2015	2016	2017	2018
Elm Road	Total	$65.05	$45.13	$33.38	$31.86	$29.39	$28.23	$26.89
	Fuel	$41.65	$32.38	$28.41	$24.46	$22.47	$21.49	$21.00
	O&M	$23.40	$12.75	$4.97	$7.40	$6.93	$6.74	$5.90
Oak Creek	Total	$38.81	$35.58	$35.15	$33.07	$35.55	$32.09	$32.28
	Fuel	$26.05	$24.18	$23.59	$23.44	$22.31	$22.61	$21.91
	O&M	$12.76	$11.41	$11.56	$9.62	$13.25	$9.48	$10.37
Pleasant Prairie	Total	$35.68	$31.09	$31.40	$28.39	$27.99	$33.76	$23.15
	Fuel	$26.48	$25.12	$24.25	$21.62	$20.41	$21.14	$20.60
	O&M	$9.21	$5.97	$7.15	$6.77	$7.58	$12.62	$2.56
Presque Isle	Total	$47.09	$47.80	$49.86	$52.28	$52.46	$49.08	$46.73
	Fuel	$33.23	$33.64	$34.33	$35.87	$30.92	$28.40	$33.20
	O&M	$13.86	$14.16	$15.53	$16.42	$21.54	$20.68	$13.52

C. Capital Additions

Q: What information do you have regarding the ongoing capital costs for the WEPCo coal plants?

A: I have compiled the historical additions to capital plant in service from the WEPCo Form 1 reports for 2012–2018. The capital additions by plant are computed from the change in capital cost reported in the annual FERC Form 1 reports.[6] These are net additions, representing the investment at the plant in the particular year, minus

[6] I eliminated the line for "Asset Retirement Costs," which are accounting allowances for future removal costs.

the cost of equipment at that plant retired. The interim accounting retirements do not generally reduce revenue requirements, since an equal amount of accumulated depreciation is removed, leaving net plant in service unchanged, so the net additions understate the costs imposed on ratepayers.

Q: What have been the historical net capital additions for the WEPCo units?

A: Table 5 lists the net annual capital additions by unit. Where the capital cost declined from year to year, I left the line blank. The value in italics is an outlier, due to major retrofits that occur rarely.

Table 5: WEPCo Net Capital Additions ($ millions)

	2013	2014	2015	2016	2017
Elm Road	$0.7	$2.8	$1.0	$1.6	$1.2
Oak Creek	$33.6	$52.7	$17.8	$25.7	$32.4
Pleasant Prairie	$9.8	*$34.0*	$5.9	$8.9	$6.4
Presque Isle	$12.4	$2.2	$1.7	$9.7	$0.2

In Table 6, I convert those capital additions to $/kW by dividing by WEPCo's ownership share of the unit, as well as the average capital additions over the last six years. Since these values are net of retirements, they understate the actual costs to ratepayers.

Table 6: WEPCo Net Capital Additions ($/kW-year)

	2013	**2014**	**2015**	**2016**	**2017**	**Average**
Elm Road	$0.6	$2.2	$0.8	$1.3	$1.0	$1.2
Oak Creek	$30.6	$48.0	$16.2	$23.4	$29.5	$29.5
Pleasant Prairie	$8.2	$28.6	$5.0	$7.5	$5.4	$10.9
Presque Isle	$34.5	$6.0	$4.6	$27.0	$0.6	$14.6

Table 7 below presents the same data, in dollars per megawatt hour.

Table 7: WEPCo Net Capital Additions ($/MWh)

	2013	2014	2015	2016	2017	Average
Elm Road	$0.3	$0.5	$0.2	$0.2	$0.2	$0.3
Oak Creek	$7.0	$12.2	$3.4	$6.7	$6.9	$7.2
Pleasant Prairie	$1.3	$5.5	$0.9	$1.5	$1.2	$2.1
Presque Isle	$6.6	$1.1	$1.0	$5.3	$0.1	$2.8

Q: Has WEPCo provided any other public data on historical capital additions for its coal units?

A: Yes, WEPCo provided gross capital additions by plant, as shown in Table 8 below, converted to $/MWh.[7] These values are less than the net increase in the capital costs reported in the FERC Form reports for some years, which is difficult to understand, since the gross increase always be higher than the net increase. Since I have not had the opportunity to further pursue an explanation for this discrepancy, I have not used the WEPCo-provided capital additions in my later analyses.

Table 8: WEPCo-Reported Historical Coal Capital Additions ($/MWh)

Plant	2016	2017	2018
Elm Road	$11.69	$4.86	$3.03
Oak Creek	$4.38	$5.36	$9.46
Pleasant Prairie	$0.46	$0.18	$0.09
Presque Isle	$0.01	$ -	$ -

In the sections that follow, I used the annual net capital additions by coal plant from Table 7.

D. Overheads

Q: What other costs are associated with continuing operation of the marginal coal units?

A: In addition to the O&M costs reported in the FERC Form 1 (e.g., page 402) for each plant, running the coal units incurs other costs that are recorded in other accounts, including:

[7] WEPCo Resp. to Sierra Club 1.3i (PSC REF# 371001)

- Labor-related overheads, such as social security, unemployment taxes, pensions, and benefits (e.g., health and life insurance, education assistance).
- Property insurance.
- Property taxes.
- Administrative costs, such as legal, human resources, supervision, regulatory and public affairs.
- Office expenses related to administration.
- Maintenance of the step-up transformers and other dedicated transmission equipment.

Q: How large are these indirect costs?

A: One way to address that question is to examine the extent to which the lead owner of each WPS or WEPCo plant marks up O&M charges to other owners, passing through these other costs. In general, the lead owner of a jointly owned plant carries various costs in non-generation accounts on its own books and charges the point owners for their share of those costs, which are usually recorded in the plant O&M of the non-operating owner. As shown in Table 2, WPL is the lead owner of Columbia and Edgewater and can charge overheads to WPS and (in the case of Columbia) MGE.[8] As the lead owner of Weston 4, WPS charges overhead cost to Dairyland Power Cooperative. WEPCo is the lead owner of Elm Road, and charges overhead cost to MGE. Table 9 provides non-fuel O&M per kWh from the 2013 to 2018 FERC Form 1 filings for the various investor-owned units and the RUS Form 12 for Dairyland.[9] The adder non-fuel O&M per kWh charged to the joint owner has a wide range, from 1% in Edgewater 4 to 258% in Weston 4.

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[8] The lead owner for each resource is shown in bold.

[9] Dairyland files its RUS reports with the Minnesota PUC, which posts those reports to its web site. I have not found any similar cost report for the other publically-owned joint owners of coal plants in Wisconsin.

Table 9: Implied Overheads for Jointly-Owned Plants, Non-Fuel O&M

Columbia	$/kWh			Markup	
	WPS	MGE	**WPL**	WPS	MGE
2018	0.0055	0.0072	0.0045	1.21	1.60
2017	0.0050	0.0070	0.0042	1.20	1.66
2016	0.0061	0.0097	0.0056	1.08	1.72
2015	0.0045	0.0093	0.0047	0.97	2.00
2014	0.0062	0.0090	0.0054	1.15	1.67
2013	0.0034	0.0057	0.0032	1.07	1.80
Average				1.11	1.74

Edgewater 4	$/kWh		Markup
	WPS	**WPL**	WPS
2018	0.0041	0.0038	1.08
2017	0.0046	0.0052	0.88
2016	0.0094	0.0065	1.46
2015	0.0046	0.0060	0.76
2014	0.0054	0.0053	1.02
2013	0.0048	0.0057	0.84
Average			1.01

Weston 4	$/kWh		Markup
	WPS	Dairyland	Dairyland
2018	N/A		
2017	0.0021	0.0079	3.82
2016	0.0040	0.0117	2.95
2015	0.0064	0.0182	2.86
2014	0.0042	0.0144	3.40
2013	0.0020	0.0095	4.86
Average			3.58

Elm Road	$/kWh		Markup
	WEPCo	MGE	MGE
2018	0.0059	0.0087	1.48
2017	0.0067	0.0101	1.50
2016	0.0069	0.0093	1.35
2015	0.0074	0.0093	1.26
2014	0.0050	0.0095	1.91
2013	0.0127	0.0114	0.89
Average			1.40

The Dairyland markups on Weston 4 seem to be too large to be just the overhead charges from WPS. The other overhead adders average 1.316. I use Elm Road's average

overhead adder of 39.83% for its analysis, and the average value of 31.64% of non-fuel O&M for WEPCo's other coal plants.

A similar analysis of fuel costs across the joint owners does not show any significant overheads excluded from the lead owners' reported fuel costs.

E. Cost Summary

Q: How do the cost components (fuel, O&M, overheads and capital expenditures) add up to a cost per megawatt-hour for continued operation?

A: I computed the total costs of keeping each operational coal unit using the public data from the tables above. Since the WEPCo FERC report did not have updated capital costs for 2018, I assumed that capital additions in 2018 would equal the average of the prior years.

Table 10: Historical Costs of Running WEPCo Coal Units ($/MWh)

		OH Adder	2013	2014	2015	2016	2017	2018
Elm Road	Fuel		$32.38	$28.41	$24.46	$22.47	$21.49	$21.00
	O&M	39.8%	$12.75	$4.97	$7.40	$6.93	$6.74	$5.90
	Capital Adds		$0.25	$0.49	$0.17	$0.25	$0.19	$0.27
	Overheads		$5.07	$1.98	$2.94	$2.76	$2.68	$2.35
	Total Cost		$50.45	$35.84	$34.98	$32.40	$31.10	$29.51
Oak Creek	Fuel		$24.18	$23.59	$23.44	$22.31	$22.61	$21.91
	O&M	31.6%	$11.41	$11.56	$9.62	$13.25	$9.48	$10.37
	Capital Adds		$7.04	$12.19	$3.41	$6.68	$6.87	$7.24
	Overheads		$3.60	$3.65	$3.04	$4.19	$3.00	$3.28
	Total Cost		$46.23	$50.99	$39.52	$46.42	$41.96	$42.79
Pleasant Prairie	Fuel		$25.12	$24.25	$21.62	$20.41	$21.14	$20.60
	O&M	31.6%	$5.97	$7.15	$6.77	$7.58	$12.62	$2.56
	Capital Adds		$1.25	$5.46	$0.89	$1.47	$1.21	$2.06
	Overheads		$1.89	$2.26	$2.14	$2.40	$3.99	$0.81
	Total Cost		$34.24	$39.12	$31.42	$31.85	$38.96	$26.02
Presque Isle	Fuel		$33.64	$34.33	$35.87	$30.92	$28.40	$33.20
	O&M	31.6%	$14.16	$15.53	$16.42	$21.54	$20.68	$13.52
	Capital Adds		$6.57	$1.14	$0.96	$5.32	$0.15	$2.83
	Overheads		$4.47	$4.91	$5.19	$6.81	$6.54	$4.27
	Total Cost		$58.84	$55.91	$58.43	$64.58	$55.76	$53.83

The all-in cost of keeping Pleasant Prairie in service was between $26 and $39/MWh, and the cost of keeping Presque Isle operating was between $54 and $65/MWh. Oak Creek fell in between those costs, ranging from $40 to $51/MWh. Excluding Elm Road's higher costs from 2013, it was similar to Pleasant Prairie with costs ranging from $29/MWh to $36/MWh.

IV. Market Prices for WEPCo's Coal-Unit Output

A. Recent Energy Prices for WEPCo Coal-Unit Output

Q: What MISO market energy prices have the WEPCo coal units faced?

A: Table 11 contains the average locational marginal price (LMP) at the MISO market node for each of WEPCo's currently operating units from 2013 to 2018, weighted by the hourly load and Table 12 provides the distribution of the LMPs for 2018.

Table 11: Average LMP ($/MWh) by Unit

	Elm Road	Oak Creek
2013	29.19	29.19
2014	35.35	35.35
2015	25.14	25.09
2016	24.88	24.92
2017	26.43	26.56
2018	28.05	28.13

Table 12: Hourly Energy Prices ($/MWh) by Unit (2018)

	Elm Road	Oak Creek
Mean	28.05	28.13
Minimum	-36.39	-35.88
25th Percentile	21.38	21.41
50th Percentile	24.56	24.58
75th Percentile	30.76	30.80
Maximum	513.45	512.39

Q: How do these energy prices compare to the short-run costs of producing energy prices from these units?

A: Table 13 summarizes that comparison for a counterfactual situation in which the plants are always available and able to dispatch in the profitable hours, but not at any other time. I started by estimating the short-run cost for each unit as the sum of fuel costs from Table 4 and an estimate of variable O&M from the Bloomberg New Energy Finance (BNEF) analysis of the U.S. coal fleet.[10] I then counted the number of hours in which the market energy price exceeded the short-run cost. The market energy price exceeded the estimated short-run cost for 2,236 hours for Elm Road and 2,848 hours for Oak Creek. I also computed the average LMP in the hours when it exceeded the short-run cost. The LMP in those profitable hours varies inversely with the number of profitable hours.[11]

[10] Ex.-Sierra Club-Chernick-2.

[11] In this section, I consider whether the units are profitable to run in a particular hour, once WEC has committed to the capital additions and fixed O&M necessary to make the plant available. Elsewhere, I consider the annual profitability of the units, including the capital additions and fixed O&M. I do not reflect the sunk capital costs of the units in any of my analyses.

Table 13: Energy Margin by Unit with Perfect Dispatch (2018)

	Elm Road	Oak Creek
Fuel + VOM ($/MWh)	30.56	28.26
When LMP exceeds Fuel + VOM		
Number of Hours	2,236	2,848
% of hours	25.8%	32.9%
Average LMP ($/MWh)	45.07	41.82
Energy Margin = LMP – (Fuel + VOM)		
$/MWh	14.51	13.57
$/kW-year	32.45	38.64

In the last section of Table 13, I computed the average energy margin for each unit in the profitable hours, in dollars per megawatt-hour (the difference between average LMP and the variable running cost) and in $/kW-year (the $/MWh margin times the number of profitable hours).

Q: How does the percentage of profitable hours compare to the units' capacity factors?

A: Both Elm Road and Oak Creek produced more energy than if they had run in every profitable hour, and not in any unprofitable hour, as shown in Table 14.

Table 14: Comparison of Profitable Hours to Capacity Factors, 2018

	Profitable Hours	Capacity Factor (%)	Difference
Elm Road	25.8%	71.3%	45.5%
Oak Creek	32.9%	49.5%	16.7%

If the coal units were always available and able to ramp up immediately to full power in the profitable hours and shut down immediately when LMP fell, the capacity factor should be very close to the profitable hours. In reality, the capacity factor for each unit is reduced by forced and maintenance outages. In addition, the coal units cannot cycle up and down fast enough to run in all the profitable hours without running in unprofitable hours.

Table 14 indicates that both currently operating WEPCo plants continued running during unprofitable hours.

Q: Why might the units be running in hours in which they are not economic?

A: There are two ways in which WEPCo may have kept the plants running at relatively high capacity factors. First, rather than bidding its coal units into the market as resources to be dispatched economically, WEPCo designated Elm Road and Oak Creek as "must-run" units, ensuring that MISO would dispatch them, regardless of cost or price.[12]

Second, when WEPCo bids the units into the MISO energy market (for the Elm Road and Oak Creek capacity in excess of the must-run level), it may bid them in at prices below their short-run marginal costs of fuel and variable O&M.

These mechanisms would allow WEPCo to force the coal units to run when they are not economic sources of energy for the region. Merchant generation owners usually do not engage in that behavior, since they would lose money on every MWh sold. Vertically-integrated utilities, on the other hand, can often count on recovering those losses from their retail (and in some cases, regulated wholesale) customers. I do not fully understand WEPCo's incentives to run the coal plants uneconomically, but it may be motivated by an interest in avoiding scrutiny of the coal plants' economics until more of their costs have been depreciated.

Since WEPCo is not subject to market discipline, as it would be if it were a merchant generator, that role falls to the Commission.[13]

Q: Does WEPCo explain why it designated some units as must-run?

A: Though WEPCo does not explain why some units are designated as must-run, it does confirm that when forecasting the generation system for 2020 all of their coal are dispatched as must-run for the entire year.[14]

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[12] WEP Resp. to Sierra Club 1.28 (PSC REF# 370985).

[13] See the testimony of Scott Hempling on behalf of Sierra Club in this docket.

[14] WEPCo Resp. to Sierra Club 1.28 (PSC REF# 370985)

Q: How were WEPCo's coal units actually dispatched?

A: Table 15 shows the average energy margins for the remaining coal units in the hours in which were actually dispatched. The percentage of hours in which each plant operated was higher than its capacity factor, since each plant operated at partial load in many hours.

Table 15: Energy Margin by Unit with Actual Dispatch (2018)

	Elm Road	Oak Creek
Fuel + VOM ($/MWh)	30.56	28.26
When Unit was Operating		
Number of Hours	7551	5980.5
% of hours	86.2%	68.3%
Average LMP ($/MWh)	28.05	28.15
Energy Margin = LMP – (Fuel + VOM)		
$/MWh	-2.51	-0.11
$/kW-year	-18.94	-0.66

Because both plants were dispatched in so many unprofitable hours, they ended up having much lower energy margins than in the perfect conditions in Table 13. Elm Road and Oak Creek actually had negative energy margins in 2018, meaning that the plants lost money even from a short term marginal cost perspective, and certainly have not been earning enough revenue to also cover capital additions, overhead and fixed O&M costs.[15]

Table 16: Average Energy LMP as Operated

	Elm Road	Oak Creek
2018	28.05	28.15
2017	26.36	26.56
2016	24.76	24.90
2015	25.13	25.09
2014	35.57	35.55
Average	27.97	28.05

Table 17 shows the average energy margin by year for each of the remaining units. Elm Road and Oak Creek appear to have lost money in the energy market in

[15] I revisit energy revenues in Section V, using confidential data provided by the Company.

each of the last four years, and the profits they made in 2014 were not enough for them to have positive energy margins on average.

Table 17: Annual Energy Margins by Unit ($/MWh)

	Elm Road	Oak Creek
2018	-2.51	-0.11
2017	-4.20	-1.69
2016	-5.80	-3.35
2015	-5.43	-3.17
2014	5.01	7.30
Average	-2.58	-0.21

B. Future Energy Prices

Q: Are market prices for electric energy in Wisconsin likely to increase dramatically over the next several years?

A: No. While price may spike occasionally, indications are that electric market prices will rise slowly, and even fall in the next few years. Table 18 shows the simple average of the ICE forward prices for MISO's Minnesota hub from July 19, 2019, for as far out as those products are traded.[16] The prices mostly fall from the second half of 2019, through 2023.

Table 18: MISO Minnesota Forward Prices ($/MWh)

Period	On	Off
ICE code	**MDP**	**MDO**
2H19	$25.76	$18.91
2020	$26.88	$18.75
2021	$25.98	$18.09
2022	$25.45	$18.08
2023	$24.76	$18.66

Q: Is there any public information on likely future electric energy prices beyond 2023?

A: Not directly. However, one major driver of electric energy prices is the cost of natural gas. Table 19 shows Henry Hub gas prices for the NYMEX forwards (the

[16] https://www.theice.com/marketdata/reports/142

HH contract) and from the EIA's 2019 Annual Energy Outlook reference case. The 2019 price in the NYMEX column is the average of monthly actual spot price to mid-July and forwards thereafter. The EIA's projection looks to be somewhat bullish in the short term. Interestingly, the forwards for MISO energy prices fall from 2019 through 2023, even though gas-price futures and forecasts are rising. That downward trend is probably the result of increasing penetration of renewables.

Table 19: Henry Hub Gas Price Projections ($/MMBtu)

	NYMEX	EIA
2017		$3.02
2018		$2.99
2019	$2.54	$3.10
2020	$2.49	$3.25
2021	$2.55	$3.24
2022	$2.60	$3.33
2023	$2.67	$3.56
2024	$2.76	$3.84
2025	$2.90	$4.20
2026	$3.02	$4.39
2027	$3.17	$4.52
2028	$3.29	$4.72
2029	$3.41	$4.84
2030	$3.54	$5.00
2031	$3.65	$5.09

C. Capacity Prices

Q: Is capacity very valuable or expensive in the MISO market?

A: No. Table 20 shows the clearing prices in Zone 2 (which includes eastern Wisconsin and upper Michigan) for each of the Planning Reserve Auctions (PRAs) that MISO has conducted.[17]

[17] From "MISO Planning Resource Auction (PRA) for Planning Year 2019-2020 Results Posting," MISO, April 12, 2019, p. 8.

Table 20: MISO Zone 2 Capacity Prices

Planning	Per unit of UCAP		$/MWh at capacity factor of		
Year	$/MW-day	$/kW-year	40%	50%	60%
2014/15	$16.75	$6.11	$1.74	$1.40	$1.16
2015/16	$3.48	$1.27	$0.36	$0.29	$0.24
2016/17	$72.00	$26.28	$7.50	$6.00	$5.00
2017/18	$1.50	$0.55	$0.16	$0.13	$0.10
2018/19	$10.00	$3.65	$1.04	$0.83	$0.69
2019/20	$2.99	$1.09	$0.31	$0.25	$0.21
Average	$17.79	$6.49	$1.85	$1.48	$1.23

Zone 2 has always cleared at the same price as Zones 3, 5, 6, and 7, and usually with other zones, as well. In three of the six PRAs (those with Zone 2 prices over $4/MW-day), Zone 1, western Wisconsin and Minnesota, cleared at much lower prices than Zone 2. If transmission capacity out of Zone 1 increases (to allow wind exports, or better integrate the MISO system), the capacity surplus in Zone 1 is likely to reduce prices in Zone 2.

There is no clear trend in the capacity prices over the five capacity auctions, despite the large amount of coal capacity retired in this period.

Q: What are the capacity prices in other regions?

A: Only four ISOs operate capacity markets: MISO, PJM, NYISO and ISO-NE. The SPP has an administrative penalty for capacity deficiencies, ERCOT has only an energy market, and the CA ISO requires that each participant contribute to resource adequacy and collects data on bilateral transactions to meet that standard.[18]

The capacity prices in the Midwestern portion of PJM, the ISO area most similar to MISO, have averaged about $36/kW-year since its first capacity auction for 2007/08, through the 2021/22 capacity period, for which PJM acquired resources in May 2018.[19] Recent prices are for capacity contracts with high

[18] The average price reported in for 2017 contract, for 2017 through 2021, averaged $21/kW-year for the unconstrained portions of the system.

[19] The 2019 auction for 2022/23 has been delayed while FERC considers potential changes in market rules.

penalties for non-performance.[20] Prices comparable to the MISO capacity product (which does not have performance penalties for conventional generation) would be several percent lower.

The prices for Upstate New York are more difficult to summarize, because NYISO conducts three types of capacity auctions (a seasonal strip auction every six months, a monthly auction every month for each of the remaining months of the season, and a spot price for each month). The average strip price for the latest sixty months for which the prices have been set (through October 2019) is under $23/kW-year, while the average spot price for the latest sixty months for which the prices have been set (through July 2019) is under $26/kW-year.

Capacity prices are higher in places where building capacity is difficult, land is scarce, labor is expensive, and transmission is constrained (e.g., New York City, New Jersey), but those conditions are not typical of Wisconsin and neighboring parts of MISO.[21]

Both the PJM and NYISO capacity markets are dominated by non-utility generators who face greater risks building for a competitive market than do the vertically-integrated utilities that dominate the MISO market, both in total and in Zone 2.

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[20] In the earlier years in which the PJM capacity market accepted both standard and high-performance capacity bids, I used the price for standard capacity, which is most comparable to the MISO capacity product.

[21] In New England, which largely meets the high-cost criteria, the ISO-NE has run forward capacity auctions since the 2010/11 delivery year, but most of those auctions have settled at administrative floors or ceilings. In the last five auctions, following the largely unanticipated retirement of capacity equivalent to over 10% of peak load, the capacity price has fallen from over $100/kW-year to $46/kW-year.

D. Other Revenues

Q: What other revenues did WEPCo report?

A: WEPCo provided historic revenues from fly ash or gypsum sales, UP rail refunds, and refined coal construction management fees (RCCF) at the plant level from 2014–2018, as well as forecasts for 2019 and 2020.[22] These are provided in Table 21 for the operating units.

Table 21: Other Revenues from Operating WEPCo Coal Plants ($ million)

Plant	Item	2014	2015	2016	2017	2018	2019	2020	Average
Elm Road	Fly Ash	$0.07		$0.15	$0.31	$1.65	$5.60	$2.63	$1.49
Elm Road	UP Rail			$1.00	$0.58	$1.08	$1.60	$0.00	$0.61
Elm Road	RCCF			$3.18					$0.45
Elm Road	Total	$0.07		$4.33	$0.89	$2.73	$7.20	$2.63	$2.55
Oak Creek	Fly Ash	$0.19	$0.52	$0.70	$0.86	$0.90	$3.75	$0.92	$1.12

E. Long-Run Economics of WEPCo's Coal Plants from Public Data

Q: How do the market revenues for the units compare to the long-run plant costs that you estimated in Table 10?

A: The discussion in Section IV.A was limited to a comparison between the short-run costs of operating the coal plants versus their market energy revenues. This comparison does not account for the long-run costs required to make the coal plants

[22] WEPCo Resp. to Sierra Club 1.3d and 1.3e (PSC REF# 371001). It is not clear who pays for the RCCF from Elm Road, or whether those revenues are already netted from the costs reported in the FERC reports. Nor is it clear whether the fuel costs that WEP reports for Elm Road are already net of the rail refunds. To be conservatively optimistic about the economics of Elm Road, I include all these revenues as benefits of operating the plant.

available, provided in Table 10, above. Table 22 shows the total costs, energy revenues and the capacity prices converted to millions of dollars for 2018.[23]

Table 22: Summary of WEPCo Average Coal Plant Costs and Revenues

		Elm Road	Oak Creek
a	Cost 2014–2018 ($/MWh)	$32.8	$44.3
b	Energy Revenue 2014–2018 ($/MWh)	$28.0	$28.1
c	2018 GWh	7,063	4,767
d	Margin with Energy ($M)	-$33.9	-$77.6
e	WEPCo Capacity Share	1,056.8	995.0
f	2018 Capacity Revenue ($M)	$1.2	$1.1
g	Other Revenue	$2.3	$1.1
h	Net profit ($M)	-$30.5	-$75.4
I	Net Profit ($/MWh)	-$4.3	-$15.8
j	Net profit ($/kW-year)	-$28.8	-$75.8

Notes:
a From Table 10
b From Table 17
c From FERC Form 1
d = (b - a) × c ÷ 1,000
e From Table 1
f = e × $1.09 ÷ 1,000
g From Table 21
h = d + f + g
I = h ÷ c × 1,000
j = h ÷ e × 1,000

As shown in Table 22, both of WEPCo's remaining coal plants have been costing customers more money than they earned. These public data suggest that Elm Road cost customers about $29 million more annually than the value of its output. Since Elm Road's costs have fallen somewhat in recent years, it has been edging closer to break even. Oak Creek costs customers about $75 million more annually.

Q: Is there any reason to expect that these units would have positive benefits for customers in the future?

A: I see no reason to expect that outcome. Most industry forecasters expect costs of renewables and storage to continue to fall, and penetration of renewable energy in

[23] The capacity revenues should be reduced about 5% to reflect the difference between rated and accredited capacity; that difference is inconsequential in this comparison.

the Midwest MISO market will continue to rise, pushing down market energy prices and reducing the value of the coal plants' output. Any environmental retrofits (such as those required to comply with the Clean Water Act) and any future limits on carbon emissions will also tend to make coal plants less economic.

Q: If WEPCo needed to purchase additional capacity to meet its MISO obligations, would that be expensive?

A: Not at the historical average market capacity prices. As shown in Table 20, the cost of capacity to replace generation with the range of capacity factors that the WEPCo coal units are likely to achieve is only about one or two dollars per MWh. If the coal energy were instead replaced by wind or solar, those resources would not only provide energy at lower cost than the coal plants, but also provide some capacity value. For solar, with a capacity factor of about 20% and a UCAP capacity credit of 50% of nameplate, the capacity credit is about 2.5 times the average hourly output, while for a power plant with a 60% capacity factor and a capacity credit of 90% of nameplate, the ratio is 1.5. Wind provides less capacity value per MWh than solar or even the coal plants, since a wind farm with a 30% capacity factor would get a capacity credit of about 16%, for a ratio about 0.5.[24] So cost-competitive energy from renewables would also contribute to satisfying WEPCo's capacity requirements.

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[24] See Section VI for a discussion of MISO capacity credit for renewables.

V. Additional Analyses from Confidential Data

Q: What forced outage and deration data did WEPCo provide?

A: While WEPCo provided forecast (only for the year 2020)[25] and historical[26] forced outage and deration rates for its Elm Road and Oak Creek units, it did not provide the historical data for its retired Pleasant Prairie and Presque Isle units. Table 23 provides annual forced outage rates, which demonstrate the annual variability in plant performance. [redacted] Elm Road is [redacted] the average that MISO reports for plants of its size as outlined in Table 3, Oak Creek is [redacted].

Table 23: Confidential Historical and Forecast Forced Outage Rates

Plant	Unit	2014	2015	2016	2017	2018	Average (2014–2018)	2020
[redacted]								

Q: What capacity factor data did WEPCo provide?

A: WEPCo provided data on 2020 forecast capacity factors for its operating coal units.[27] Table 24 contains these numbers, and Figure 2 plots them alongside the historical capacity factors from Figure 1.

[25] WEPCo Resp. to Sierra Club 1.5p (PSC REF# 370998)

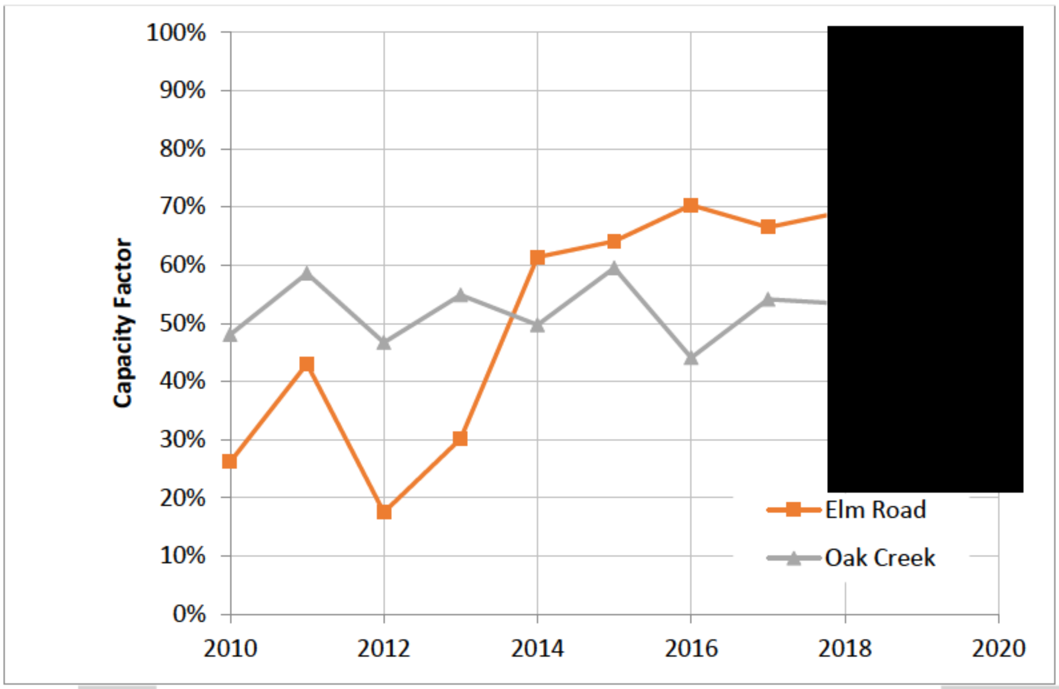
[26] WEPCo Resp. to PSCW FCP DM-5 (PSC REF# 362818)

[27] WEPCo Resp. to Sierra Club 1.5o (PSC REF# 370998)

Table 24: Confidential 2020 Forecast Capacity Factors

Plant	2020 Forecasted Capacity Factor
Elm Road	[redacted]
Oak Creek 4	[redacted]

Figure 2: Confidential Historical and Forecast Capacity Factors of WEPCo Coal Plants



[redacted] WEPCo projects that the capacity factor for Oak Creek will [redacted], it [redacted] expects Elm Road capacity factor to [redacted] in 2020.

Q: What energy revenues did WEPCo report?

A: Table 25 contains the yearly energy revenues that WEPCo reported for each of its plants[28], divided by the WEPCo share of generation for those plants in order to provide a $/MWH revenue value. Table 26 compares these values to those that I estimated using the average LMPs in Table 16.

[28] WEPCo Resp. to Sierra Club 1.3a (PSC REF# 371000)

Table 25: Confidential WEPCo Reported Energy Revenue by Unit ($/MWh)

Plant	Unit	2015	2016	2017	2018	Average
Elm Road	1-2	[redacted]				
Oak Creek	5-8					
Pleasant Prairie	1-2					
Presque Isle	5-9					

Table 26: Confidential Comparison of Public Estimate of Energy Revenues to WEPCo Confidential Information ($/MWh)

	Elm Road	Oak Creek
Average LMP 2014-18	$27.97	$28.05
WEPCo Reported Revenue 2015-18	[redacted]	
Difference		

WEPCo reported energy revenues [redacted] are [redacted] than my estimates from the public data, for which I had only gross output. Adding the differences in Table 26 to my estimate of operating losses in Table 22 [redacted]

Q: Have you updated your Table 22 using the energy revenues from Table 25?

A: Yes, Table 27 provides that update.

Table 27: Confidential Summary of WEPCo Average Coal Plant Costs and Revenues

		Elm Road	Oak Creek
a	Cost 2014-2018 ($/MWh)	$32.8	$44.3
b	Energy Revenue 2014–2018 ($/MWh)	[redacted]	[redacted]
c	2018 GWh	7,063	4,767
d	Margin with Energy ($M)	-$2.95	-$82.08
e	WEPCo Capacity Share	1,056.8	995.0
f	2018 Capacity Revenue ($M)	$1.2	$1.1
g	Other Revenue	$2.3	$1.1
h	Net profit ($M)	[redacted]	[redacted]
I	Profit per MWh	[redacted]	[redacted]
j	Net profit ($M)	[redacted]	[redacted]

Notes:
- a From Table 10
- b From Table 25
- c From FERC Form 1
- d = (b - a) × c ÷ 1,000
- e From Table 1
- f = e × $1.09 ÷ 1,000
- g From Table 21
- h = d + f + g
- I = h ÷ c × 1,000
- j = h ÷ e × 1,000

Q: How much extra would WEPCo customers pay annually in order to keep uneconomic coal plants operating at the profit levels in Table 27?

A: [redacted] Elm Road [redacted], Oak Creek has been [redacted]

Q: To what extent can the WEPCo coal units vary their output in response to changes in load or market energy price?

A: In general, large coal units are very slow to respond to changing conditions. Table 28 elaborates on the limited load-following abilities of each of the WEPCo coal units.[29] The various units have a minimum up time of [redacted]. The full plant ramp rate for the units ranges from [redacted], equivalent to [redacted] to get from first generation to full power.

[29] WEPCo Resp. to Sierra Club 1.8 (PSC REF# 370993)

Table 28: Confidential WEPCo Coal Unit Load-Following Parameters

Plant	Unit	Minimum Up Time (Hrs)	Minimum Down Time (Hrs)	Unit Ramp Rate (MW/min) up and down
Elm Road	1	[redacted]	[redacted]	[redacted]
Elm Road	2	[redacted]	[redacted]	[redacted]
Oak Creek	5	[redacted]	[redacted]	[redacted]
Oak Creek	6	[redacted]	[redacted]	[redacted]
Oak Creek	7	[redacted]	[redacted]	[redacted]
Oak Creek	8	[redacted]	[redacted]	[redacted]
Pleasant Prairie	1	[redacted]	[redacted]	[redacted]
Pleasant Prairie	2	[redacted]	[redacted]	[redacted]
Presque Isle	5	[redacted]	[redacted]	[redacted]
Presque Isle	6	[redacted]	[redacted]	[redacted]
Presque Isle	7	[redacted]	[redacted]	[redacted]
Presque Isle	8	[redacted]	[redacted]	[redacted]
Presque Isle	9	[redacted]	[redacted]	[redacted]

Q: Did WEPCo provide any confidential data on its dispatch strategy for its coal units?

A: As stated earlier in this testimony, WEPCo publicly revealed that it forecasts all of its coal units as must-run all year round. It also provided data on how the plants were dispatched between 2017 and 2018.[30] This information is summarized in Table 29.

[30] WEPCo Resp. to Sierra Club 1.3v (PSC REF# 371000)

Table 29: Confidential Annual Unit Operating Status

Plant	Unit	2017 Must Run	2017 Outage	2017 Econ-omic	2017 Emerg-ency	2018 Must Run	2018 Outage	2018 Econ-omic	2018 Emerg-ency
Elm Road	1	[redacted]							
Elm Road	2								
Oak Creek	5								
Oak Creek	6								
Oak Creek	7								
Oak Creek	8								
Pleasant Prairie	1								
Pleasant Prairie	2								
Presque Isle	5								
Presque Isle	6								
Presque Isle	7								
Presque Isle	8								
Presque Isle	9								

The confidential historical data [redacted] WEPCo's current dispatch strategy; [redacted].

Q: Please summarize the effect of WEPCo's confidential data on your conclusions in section IV.

A: The confidential data from WEPCo has confirmed my conclusions based on public data.

VI. Costs of Renewables

Q: Has WEPCo provided you with any information on wind PPAs?

A: WEPCo claims it does not estimate its own levelized costs of wind[31] and also declined to provide any information on the price of energy from wind farms it does not own.[32]

[31] WEPCo Resp. to Sierra Club 1.9 (PSC REF# 370973)

[32] WEPCo Resp. to Sierra Club 1.10 (PSC REF# 370208)

Q: What wind PPA prices are reported by public sources?

A: Table 30 shows levelized PPA prices compiled by LevelTen Energy for the period from October 2018 to June 2019 for wind PPA offers in its northernmost MISO region, covering North Dakota, Minnesota, Wisconsin and Upper Michigan.[33] Table 30 also shows the levelized prices for utility-scale solar projects. The PPA prices in the table refer to the most competitive 25th percentile offer prices associated with projects with contract tenors of 10 to 25 years. LevelTen does not publish all combinations of locations and contract start dates.

Table 30: LevelTen Energy Levelized North-MISO P25 PPA Prices ($/MWh)

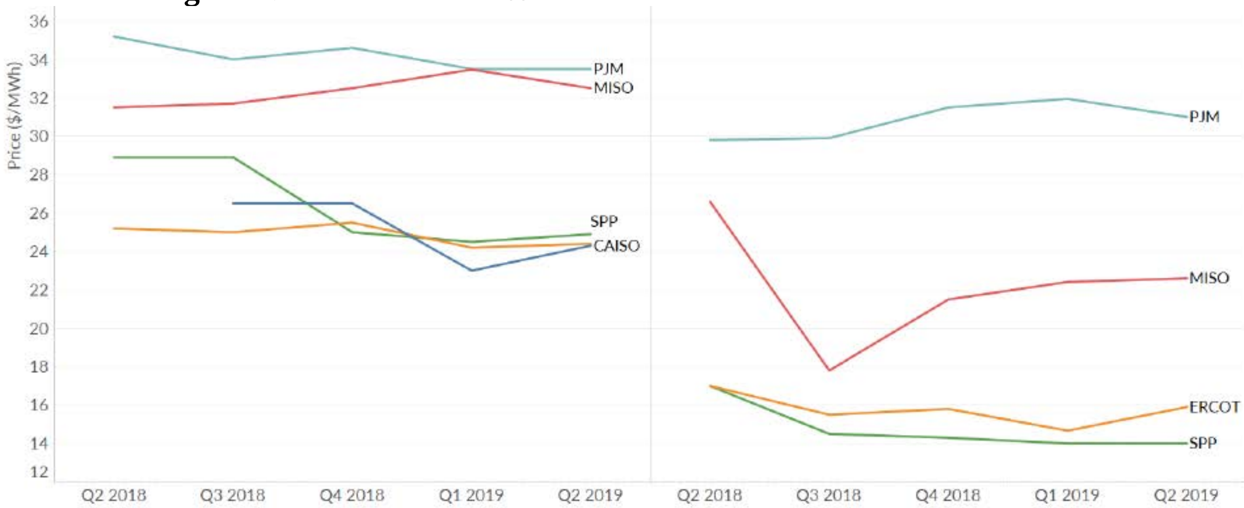
	Wind PPA Price	Solar PPA Price
Q3 2018	$17.4	NA
Q4 2018	$20.0	$34.2
Q1 2019	$20.7	$34.6
Q2 2019	$15.7	$34.2

These prices are consistent with prices reported elsewhere, with the solar prices reflecting the higher latitude of Wisconsin, compared to Colorado or Texas.

Figure 3 below shows the levelized MISO solar and wind PPA price trajectories by ISO over the past few quarters. LevelTen describes these data as price indices; the prices are higher than the P25 values, and may represent median prices.

33 https://leveltenenergy.com/.

Figure 3: LevelTen Solar Wind PPA Indices



Q: How much capacity credit does MISO give for solar and wind resources?

A: For MISO's most recent planning year, 2019/2020, the capacity credit for wind generation was set at 15.7%, which translated to 2,855 MW out of 18,210 MW of unforced wind capacity potentially qualifying under Module E-1 of MISO's tariff. The 2019-2020 wind capacity credit is 0.5 percent points higher than the 2018-2019 credit. While MISO consistently assumes that wind's capacity credit will decline as penetration rises, its estimate of the capacity contribution has increased over 20% since 2011, even as wind penetration has nearly doubled.[34] The default solar capacity credit for the 2019-2020 planning year remains at 50%.

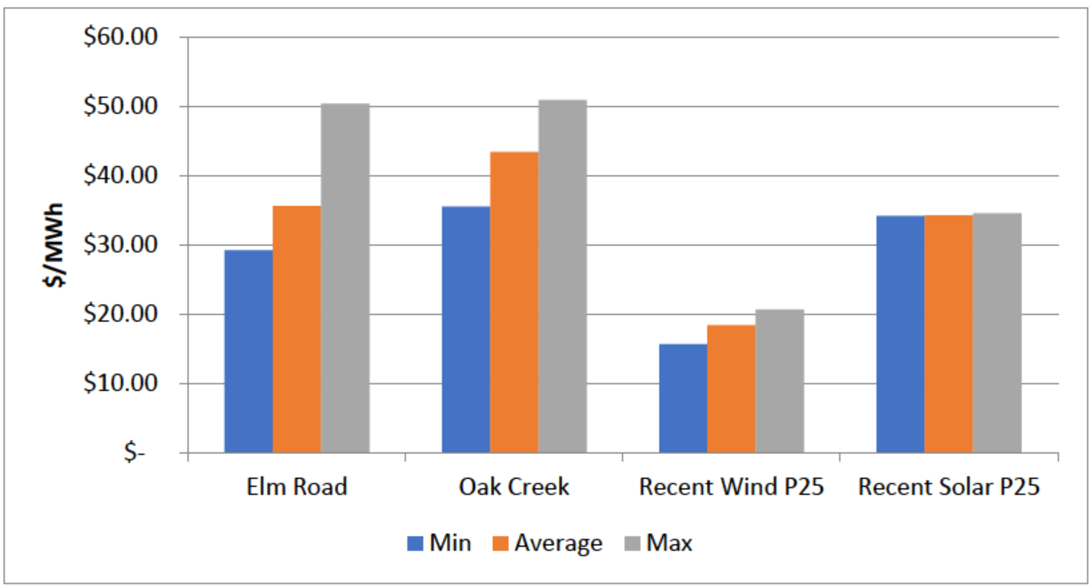
Since MISO credits wind with less capacity per MWh than a baseload power plant, replacement of coal units with mostly wind energy would require some short- or long-term market capacity purchases, addition of solar and/or storage resources, and/or addition of demand response.

[34] MISO Planning Year 2019-2020 Wind & Solar Capacity Credit, December 2018, p. 9.

Q: How do these costs of renewables compare to the costs of continuing to operate WEPCo's coal resources?

A: Figure 4 compares the costs of continuing to run the coal resources with the costs of recent renewable PPAs. For each coal resource, I present the lowest annual $/MWh cost, the average cost, and the maximum cost for 2013 – 2018 from Table 10. For renewables, I present the minimum, average, and maximum costs of the MISO North PPAs for the past four quarters from Table 30.

Figure 4: Costs of Renewable PPAs and WEPCo Coal Plant Operation



As Figure 4 shows, the entire range of wind prices from low to high are lower than the low cost for both coal units. The average and high prices of solar are cheaper than the average and high prices of both coal units as well. Only Elm Road outperforms solar in a low cost year. Notably, even its cheapest year Oak Creek is more expensive than the high cost estimates of wind and solar. Since a solar plant provides more energy in the high-value on-peak period, and provides an unusually large amount of capacity per unit of energy, it may be cost-effective even if its energy price were somewhat higher than the cost per MWh of a coal plant.

Q: How much could ratepayers save if the coal units were replaced with wind energy?

A: Just comparing the costs of energy, customers would save over $220 million annually replacing $39/MWh coal with $19/MWh wind energy over the 11,830 GWh reported for WEPCo's share of Elm Road and Oak Creek in WEPCo's 2018 FERC Form 1. Since this change in resources would change the dispatch of WEPCo's system into the MISO market, the overall effect of the transition would be somewhat different from this top-level estimate.

VII. Other Studies of Coal-Plant Economics

Q: Have other recent studies reviewed the prospects for economic coal plant operation?

A: Yes. Bloomberg New Energy Finance (BNEF), the Brattle Group and the Coal Tracker Initiative released conducted separate analyses of coal-plant cost-effectiveness in 2018.

A. The BNEF Study

Q: What did the BNEF study examine?

A: The Bloomberg study, attached as Ex.-Sierra Club-Chernick-2, covered the six-year period of 2012 through 2017, for 903 units totaling 280 MW of nameplate capacity, excluding combined heat and power units.[35] The authors compared energy, capacity and byproduct revenues by unit to the fuel, variable O&M and emissions charges, to compute what they call the "short-run margin." Adding fixed O&M to

[35] Half of U.S. Coal Fleet on Shaky Economic Footing: Coal Plant Operating Margins Nationwide, William Nelson and Sophia Liu, March 26, 2018.

the costs produces the “long-run margin.” The study reports environmental capital additions, but does not include any capacity additions in the profitability analysis.

Q: What did the BNEF study conclude?

A: The study’s conclusions included the following:

> By our estimates, 48% of the coal fleet (135 of 280 GW) posted negative margins from 2012-17…
>
> We find ourselves awestruck by the resilience of U.S. coal. Plants persist even when they cost more to run than replace. As we hunt for coal closures, beware of the sometimes tenuous link between ‘economics’ and ’retirement decisions’. The link is especially weak in regulated regions, where high-cost coal runs regularly out of merit. …
>
> The majority of ‘uneconomic’ units (130GW of 135GW) are regulated. They are kept online by virtue of cost-plus pacts that partially insulate owners from shifting economics. … (p. 1)
>
> Coal plants were originally designed to run baseload – to sell large volumes of electricity with healthy short-run operating margins (i.e. dark spreads). This was necessary to cover relatively high fixed costs. Since the shale boom, collapsing dark spreads and dwindling capacity factors have cut deeply into coal’s energy revenues – so much so that plants sometimes fail to cover fixed operating costs. Ongoing operating losses can drive plants to retire.
>
> Simply boosting output is not an option. Plants have reduced their capacity factors precisely because in many hours, fuel prices are higher than power prices. Running more would mean running at a loss. (p. 8)

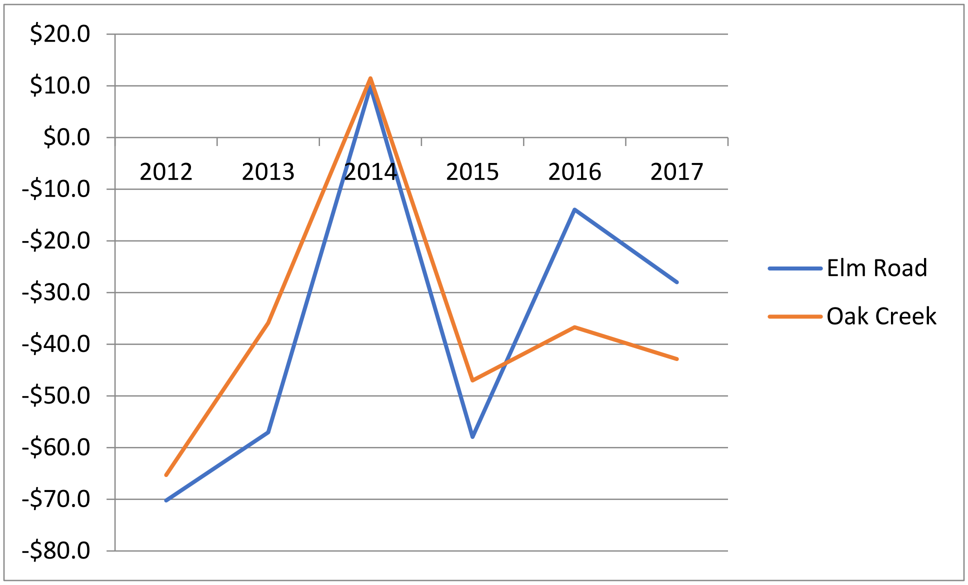
Q: What does BNEF conclude about WEPCo’s coal plants?

A: Table 31 provides BNEF’s results for each of the WEPCo plants, for each year and cumulative for the period. Overall, both plants lost money overall, and especially in the past three years.

Table 31: BNEF Estimates of WEPCo Unit Operating Profit ($/kW)

	2012	2013	2014	2015	2016	2017	Total
Elm Road	-$70.2	-$57.0	$9.9	-$57.9	-$13.9	-$28.0	-$217.3
Oak Creek	-$65.3	-$35.9	$11.5	-$47.0	-$36.7	-$42.9	-$216.2

Figure 5: Annual Unit Operating Profit, per BNEF



Since these are the annual profits without capital additions or overheads, these results understate the losses that WEPCo's customers have experienced from both the Elm Road and Oak Creek units. Including capital additions and overheads, the losses on those units would be even larger.

B. The Brattle Study

Q: What were the results of the Brattle study?

A: The Brattle Group study, attached as Ex.-Sierra Club-Chernick-3, used ABB's Velocity Suite data (the default data for PROMOD) to estimate the 2017 net margin

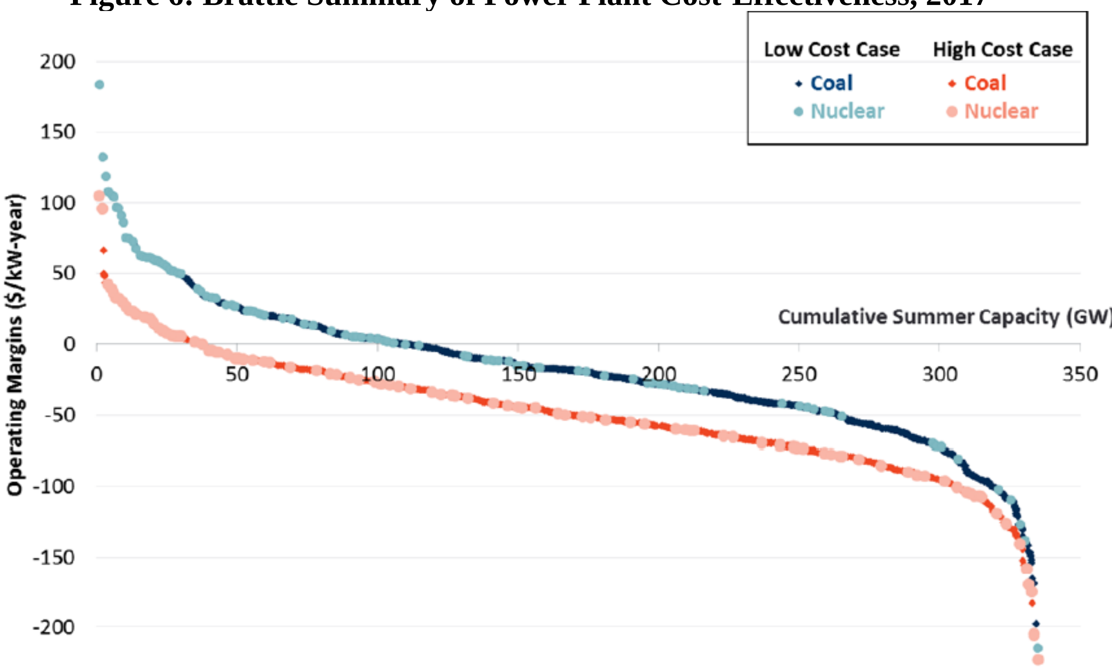
for each domestic coal plant (as well as each nuclear plant).[36] Brattle does not identify the results for specific units, but does provide aggregate results, as summarized in Table 32.

Table 32: Brattle Results for Coal Plant Economics, 2017

		Capacity with Revenue Shortfall			
		Gigawatts		Percentage of Total	
	Total Capacity (GW)	Low-Cost Case	High-Cost Case	Low-Cost Case	High-Cost Case
RTO	160.1	120.1	154.2	75%	96%
Non-RTO	75.7	65.3	69.5	86%	92%
Total	235.8	185.4	223.7	79%	95%

Brattle also plotted the distribution of plant profitability, as shown in Figure 6.

Figure 6: Brattle Summary of Power Plant Cost-Effectiveness, 2017



[36] The Cost of Preventing Baseload Retirements: A Preliminary Examination of the DOE Memorandum, Metin Celebi, et al, July 2018. Brattle reports that it excluded another 11.7 GW of coal units (averaging 37 MW per unit) were listed as having no generation and in most cases no cost data.

The dark data points, representing the coal plants, are sometimes obscured by the large light data points that Brattle used for the nuclear units.

Q: How do the costs of the coal units in the Brattle analysis compare to the costs of the WEPCo coal units?

A: The average costs of the coal units in the Brattle analysis are listed in Table 33. Brattle used unit-specific fuel and VOM costs from the ABB database, generic FOM values from EPA and capital additions (CapEx) costs from EIA.

Table 33: Brattle Average Coal Forward Costs ($/MWh)

	Low-Cost Case	High-Cost Case
Fuel Costs	$22.30	$22.30
VOM	$1.56	$4.91
FOM	$7.14	$8.51
Ongoing CapEx	$4.97	$4.97
Total	$35.97	$40.69

Brattle's fuel costs are similar to those I calculated for WEPCo's coal units, summarized in Table 10. Elm Road and Pleasant Prairie had lower O&M costs than Brattle's estimates and Presque Isle and Oak Creek had higher O&M costs. I also calculated lower capital addition costs for most of the coal units, with the exception of Oak Creek again being more expensive than the Brattle estimate.

VIII. Dues and Contributions

Q: Which association dues and contributions that Wisconsin Gas and WEPCo have proposed to include in the test year revenue requirement would you like to call to the Commission's attention?

A: The Companies have provided lists of dues and contributions included in the test year revenue requirement.[37]

[37] WEPCo Resp. to Sierra Club 3.3 (PSC REF# 372987).

Some of the dues strike me as being non-controversial, based on their organizational designations (and my understanding of what those organizations do), such as the National Association of Corporate Directors, the American Association of Blacks in Energy, Hispanic Professionals, Better Business Bureau of Wisconsin and National Minority Supplier. But a number of the organizations appear to be heavily involved in lobbying, policy advocacy, and public relations, incurring costs that might not be recoverable in rates if they were incurred and reported directly by the Companies, such as:

- American Gas Association (AGA),
- Edison Electric Institute (EEI),
- National Hydropower Association,
- Wisconsin Manufacturers and Commerce,
- Wisconsin Utilities Association,
- Wisconsin Utility Investors, and
- the Metropolitan Milwaukee Association of Commerce.

These seven organizations account for over 90% of the Companies' dues and contributions.

I would expect that these organizations would spend significant sums on such activities as funding policy and political advocacy and public relations efforts that do not advance the interests of ratepayers as a whole.

Q: What standards should the Commission apply to recovery of these costs from ratepayers?

A: I am informed by counsel that Wisconsin law precludes the Companies from charging ratepayers for "advertising" costs (defined broadly to include advertising

paid for through contributions to trade associations), unless the utility demonstrates that the costs provide specific, defined value for ratepayers.[38]

Aside from Wisconsin statutory requirements, the general rule for utility regulation is that costs should be charged to customers only if the costs either:

1. are expected to benefit customers, or
2. are required by law or regulation.

The Companies have not shown that these costs meet those or similar standards.

Q: Do you have any specific concerns about ratepayers paying for payments to the organizations listed in WEPCO's Response to Sierra Club 3.3?

A: Yes. While EEI and AGA sponsor studies and facilitate exchange of information among utilities that just help them do their job better, they also sponsor reports, lobby public officials and advertise to the public and decisionmakers to pursue the interests of utility shareholders and managers.

Wisconsin Utility Investors sounds like the kind of organization that would also be involved in lobbying and public relations on issues that do not particularly align with the interest of ratepayers. Each utility's revenue requirements already include its costs to address issues in regulatory proceedings. It is not reasonable for ratepayers to fund yet another surrogate to also represent the utility owners in regulatory proceedings. Of course, the shareholders can spend their own money on regulatory participation, to the extent permitted by the Commission. The issue here is whether they can charge the ratepayers for that advocacy.

[38] Wis. Stat. § 196.595(2), (2m) and Wis. Admin. Code ch. PSC 12; Wis. Stat. § 195.595(1)(b).

Q: Do the Companies adequately identify the amount of each organization's budget go to lobbying, advertising, or other activities that should not be charged to ratepayers?

A: No. WEPCo asserts that "$5,292 (21%) of dues represent estimated lobbying expenses" for the National Hydropower Association.[39] WEPCo also claims that the value it reports for its EEI expense is for the "amount unrelated to lobbying" and both Companies similarly assert that the reported costs for AGA are for the "amount unrelated to lobbying." The Companies do not define "lobbying" as they use that term, show that all lobbying expenses have been excluded, or demonstrate that the remaining expenses are legally chargeable to customers. The Companies have provided no evidence that the non-lobbying costs either are for activities other than advertising, or are for advertising that provides specific, defined ratepayer benefits.

Q: How should the Commission deal with these claimed expenses?

A: The Commission should not allow the Companies to recover any of the costs of the seven organizations I have flagged, unless and until the Companies demonstrate that the claimed expenses benefit ratepayers by improving utility operations or cutting costs.

Q: Does this conclude your testimony?

A: Yes.

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[39] WEPCo Resp. to Sierra Club 3.3 (PSC REF# 372987). It does not appear that even that amount has been subtracted from the test year expenses, unlike some portion of the EEI and AGA dues.